Appendix 9-1

Coffman Cathodic Protection Report

Cathodic Protection
And
Other Corrosion Control Considerations
For The
DOE Natural Gas Spur Line

COFFMAN ENGINEERS

http://www.coffman.com/

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Executive Summary

Coffman Engineers was tasked by Michael Baker to provide preliminary engineering information regarding cathodic protection of the DOE Natural Gas Spur Line. Based on information provided by Michael Baker, and Coffman Engineers experience in arctic environments and pipeline corrosion control technologies, the following preliminary engineering summary of recommendations are offered.

1. Coat the pipeline with a high performance industrial coating system as to be determined by Michael Baker. The coating should be resistant to cathodic disbondment and exhibit good abrasion resistance relative to the soil stresses and handling anticipated during construction and operation. In high abrasion areas, the coating system should be supplemented with a proven rock shield protective covering that is compatible with cathodic protection.
2. Collect detailed soils data down to and below the proposed pipeline elevation(s) including soil composition (silts, sands, organics, clay, gravel, etc.), water content and groundwater elevation, pH, redox potential, chloride and sulfate content, resistivity and identify permafrost locations.
3. Use impressed current cathodic protection (CP) systems for the primary CP system at the compressor stations as well as the transmission pipeline. Separate impressed current CP systems may be needed for station and line piping. Approximately 20 or more systems are anticipated at this time. Supplemental galvanic systems may also be required, depending on the soil test results.
4. Fittings should be used to electrically isolate the compressor station piping from the transmission line piping and the various buildings; however, resistive bond stations should be installed to allow controlled amounts of protective current to be distributed between the station piping and the transmission line.
5. Telluric current effects should be accounted for by installing resistive bonds and galvanic anodes (current discharge capabilities) as determined by the final design.
6. Install one CP coupon test station with dual coupons (CP and free corroding coupons) approximately every mile, in high consequence areas, and where there are significant terrain changes. Coupon size should be optimized for a 20-inch diameter line.
7. Develop a CP commissioning, monitoring and maintenance plan that complies with all applicable state and federal regulations and industry practices.
8. Develop an Integrity Management Plan that calls for the use of smart pigs to detect corrosion, cracks and other flaws in the piping. Construct a pipeline suitable for pigging operations. Correlate pig data with CP data.

It should be noted that these recommendations are made with limited preliminary information about the actual right-of-way conditions and the methods and means proposed for construction. A significant amount of work is required to fully address all the concerns mentioned in this report and develop a complete strategy to mitigate the corrosion risks on the proposed pipeline routes.

From a cost comparison perspective, the shorter pipeline route (Delta Junction option) will likely have a lower installation and operating cost. Determining the actual cost and difficulty of installing the pipeline along either right-of-way (which will far out weigh the corrosion control cost factors) will be left to others for analysis.

Introduction

Coffman Engineers was tasked by Michael Baker to prepare a document outlining the technical considerations needed to address the requirements for cathodic protection (CP) of a proposed gas spur line from either Fairbanks or Delta Junction to a point near Palmer or Beluga, Alaska. It was also requested to provide preliminary recommendations based on currently available project information and what is known about the behavior of CP in arctic and sub-arctic environments.

Project Description

There are currently two proposed spur line routes being considered to supply natural gas to the south central region of Alaska. The first option connects the proposed spur line to the new Alaska Gas Pipeline (AGP) north of Fairbanks and follows the existing Highway 3 corridor (Parks Highway) south to the Big Lake/Beluga area, which is across Cook Inlet and west of Anchorage. At that point the spur would tie into an existing gas transmission line that runs from the Beluga gas field to Anchorage. The total distance of this option is approximately 322 miles.

The second option ties into the AGP near Delta Junction and proceeds south along the Highway 4 corridor (Richardson Highway) to a point near Gulkana where it traverses west towards Palmer, Alaska. After traversing cross country approximately 18 miles, the spur would roughly follow the Highway 1 corridor (Glenn Highway) from a point 12 miles west of Glennallen to Palmer. Total distance of this option is approximately 281 miles.

Either option would use similar means and methods of construction, as identified by Michael Baker. Preliminary design criteria are listed below:

- 20-inch nominal diameter X-70 welded steel transmission piping
- Pipeline coated with fusion bonded epoxy
- Direct buried pipeline with depth of burial approximately 4 feet
- Ambient temperature type operating environment
- 2,500 psi nominal working pressure
- 2 compressor stations installed along the pipeline route

Regulatory Requirements

The primary governing criteria for the construction and operation of natural gas transmission lines of the type proposed is Title 49 CFR Part 192. This federal regulation is administered in Alaska by the US Department of Transportation's (DOT) Office of Pipeline Safety, which is part of DOT's Pipeline and Hazardous Materials Safety Administration (PHMSA). Imbedded by reference in this regulation is reference to a number of industry standards. Of particular interest for this report are the references to the following.

- ASME/ANSI B31.8 "Gas Transmission and Distribution Piping Systems"
- ASME/ANSI B31G "Manual for Determining the Remaining Strength of Corroded Pipelines"
- NACE International (NACE): NACE Standard RP-0502-2002 "Pipeline External Corrosion Direct Assessment Methodology"
- Gas Technology Institute (GTI). (Formerly Gas Research Institute): GRI 02/0057 "Internal Corrosion Direct Assessment of Gas Transmission Pipelines Methodology"

While not referenced directly, two NACE recommended practices will play a key role in developing a cathodic protection strategy on the spur line option that is chosen. These are NACE International (NACE) Standard RP0169-2002 “Control of External Corrosion on Underground or Submerged Metallic Piping Systems” and NACE Standard RP0104-2004 “The Use of Coupons for Cathodic Protection Monitoring Applications”.

Both pipeline options will be required to have cathodic protection applied to all buried and submerged sections of the pipeline. Additional monitoring and maintenance requirements will also be required to demonstrate that the pipeline is adequately protected.

Cathodic Protection Options

Cathodic protection is commonly applied by two methods. The first is through the use of sacrificial anodes. This methodology is sometimes referred as a galvanic system because the anodes used are higher in the galvanic series than the steel they are protecting. With this type of system a metal rod, ingot or ribbon of either high purity zinc or magnesium is connected to the pipeline through a test station via an insulated wire. The metallic anode sacrifices itself and decomposes in order to protect the exposed external steel surface of the pipeline where there is a defect in the coating system. As the anode corrodes or decomposes, it discharges current (DC) that travels to the pipeline, through the earth, and collects at coating defect locations, which are often referred to as holidays. The consumption rate is directly proportional to the current output of the anode. This type of system was initially installed on the Trans-Alaska Pipeline System (TAPS). Initially TAPS used two zinc ribbon anodes to protect the pipeline segments between pump stations (See Appendix A for an example drawing of a ribbon anode system).

The second method employs the use of a DC current source (usually an AC/DC rectifier) and is often referred to as an impressed current system. This method of CP operates by impressing a DC current through the soil by way of an anode groundbed. Current travels to the pipeline, through the earth, where it collects on the exterior pipe surfaces, at defects in the coating. Current then travels back to the rectifier by way of the metallic path in the pipeline and eventually through wires that are routed from the pipeline to the rectifier. There are many configurations for impressed current CP systems. Deep groundbed anodes, for example, are used to protect larger areas of pipelines and distributed buried assets such as those found at pump/compressor stations, refineries and terminals. Rectifiers and deep groundbed anodes have been installed along TAPS to provide additional current to protect the pipeline and other buried structures (See Appendix B for an example of a typical deep anode groundbed system).

Each type of cathodic protection system has its advantages and limitations, some of which follow:

Sacrificial Anode Systems Advantages

- No external power required
- No voltage regulation required
- Minimal cathodic protection interference issues
- Anodes can be readily added
- Low maintenance
- Fairly uniform distribution of current in low resistivity soils
- During construction, installation costs can be reasonably low
- Minimal impact to right-of-way

Sacrificial Anode Systems Limitations

- Limited driving potential and current distribution
- Limited current output
- Only a small area protected by a single anode (typically 10 to 1,000 feet – soil dependent)
- Limited use in high resistance soils
- Remedial anode placement after construction can be expensive
- Current output limitations could pose a problem as the coating system deteriorates
- Poor quality anodes can passivate further limiting their output
- Connections to the pipe must be made frequently (approximately 1,000 feet) and are subject to damage from vandals, animals, avalanches and floods

Impressed Current Systems Advantages

- Driving voltage is highly variable
- High output current available from a single source
- Fixed or auto regulating voltage available
- Can be used effectively in high resistivity soil
- Can protect large areas of pipeline from a single source (1 to 20 + miles)
- During construction, installation cost can be reasonable
- Minimal impact to right-of-way

Impressed Current Systems Limitations

- Subject to power failures, damage and vandalism
- Requires external power
- Monthly power costs and occasional maintenance
- Cathodic interference issues are possible
- Requires bi-monthly rectifier monitoring and inspections
- Overprotection can cause premature coating failure and stress corrosion cracking in extreme cases
- Current distribution may be uneven through the area of influence
- Additional groundbeds can be added, but at significant expense

For this project, it is recommended that the primary source of cathodic protection be impressed current systems. It is likely that at least 20 impressed current rectifier/groundbed systems will be needed. These may be a mix of deep groundbed and distributed type systems. Additional localized protection may be needed using sacrificial anodes and/or smaller distributed type impressed current systems using canister type anodes, mixed metal oxide ribbons or Anodeflex® type products.

Design Considerations

The following design considerations should be addressed as the project progresses from a preliminary engineering conceptual phase to a formal design development phase. Many of the issues are interrelated and resolving one may impact the ability to resolve another.

Soils:

Common soil characteristics along the proposed pipeline routes include silt, sand, gravels, peat, organics, rock and water. Water content in each of these could vary significantly depending on location and time of year. Many of these soils will freeze seasonally and some may be frozen year round. Where soils are saturated with water, higher corrosion rates can be expected.

Factors that affect the corrosivity of soils include soil resistivity, soluble salt content, pH, soil type (permeability), aeration, moisture content, redox potential, amount of microbes in the soil and stray currents. No single factor or measurement should be used to determine the corrosivity of soil.

One of the best criterions for estimating the corrosivity of a soil is to determine its resistivity, which depends largely upon the nature and amount of dissolved salts in the soil. It is generally recognized that soluble salts, such as chloride and sulfate ions, increase the corrosivity of soil. Temperature, moisture content, compaction and presence of inert materials also affect soil resistivity.

Soil resistivity affects corrosion in several ways. The lower the resistivity, the better the soil conducts current flow and the greater the soil corrosivity. Low resistivity soils may contain high concentrations of soluble salts. The salts attack the protective oxide films on the steel surface, accelerating the rate of the electrochemical reactions, therefore increasing the corrosivity of the soil.

A general guideline for soil corrosivity is listed below:

Soil Resistivity (Ohm-cm)	**Soil Corrosivity**
Below 500	Very Corrosive
500 – 1,000	Corrosive
1,000 – 2,000	Moderately Corrosive
2,000-10,000	Mildly Corrosive
Above 10,000	Progressively Less Corrosive

The preceding guideline may be used as a soil corrosivity indicator, but no single measurement should be used to determine the corrosivity of soil. Corrosion of structures, where bacteria, oxygen concentration cells and other corrosion mechanisms exist, has been documented in soils in excess of 100,000 ohm-cm.

Soil uniformity is important because of the possible development of localized corrosion cells caused by discontinuous soils. Different soil types in contact with a pipeline can cause anodic (where corrosion occurs) and cathodic areas within a pipeline segment. The same is true for uniformity of aeration. If one segment of soil contains more oxygen than a neighboring segment, a corrosion cell may develop from the difference in potential. This cell is called a differential aeration cell.

The classic example is a pipeline passing from one type of soil to another. If a pipeline crosses two or more different types of soil with different oxygen permeation characteristics (e.g. sand and clay), the concentration cell (i.e., an oxygen concentration or aeration cell) can be formed. In such a cell, the anode is located at the area where the supply of oxygen is low and at this location localized corrosion will occur. In this case, the sand will be aerated, whereas the clay is impermeable and essentially devoid of oxygen. The part of the pipeline in contact with clay will then become the anode and suffer damage (if not protected by additional means).

Corrosion cells can also arise when a buried structure is surrounded by mixed soils containing, for example, lumps of clay. Pitting takes place under these lumps, where they are in contact with the metal.

A similar situation occurs wherever a pipeline passes a paved road or a body of water. In addition to the specific effects of road salt and other conditions, oxygen is excluded from the areas under the pavement, so that the pipe under the crossing (which is the most difficult to get at if repair is needed) is precisely the site where corrosion is inevitable. The pipe segment outside of the roadway serves as the cathode.

A concentration cell can also arise on a structure which stretches through the groundwater table, since the supply of oxygen is good above but not below the groundwater table. Localized corrosion can then take place just below the groundwater table.

Soil resistivities along the pipeline route may range from approximately 500 ohm-cm to highs exceeding 1,000,000 ohm-cm. The microenvironment near the pipeline surface may also be quite different than the bulk soil in the surrounding area. An example is a shot rock ditch. In areas where a pipeline passes through a region of solid rock, the rock is blasted out and the pipeline is laid in the ditch often with material crushed from the rock that was removed. While the bulk rock may have little moisture and a resistivity in excess of 1,000,000 ohm-cm, the trench next to the pipe may fill with water and reduce the resistivity to significantly lower levels. In areas of steep mountainous terrain, water may flow like a stream next to the pipe during certain times of the year. Each type of soil in each region requires a careful analysis to assist in the planning process for a CP installation.

The chemical composition and the degree of acidity or alkalinity of the soil affect the corrosion rates of metals in soils. In general, decreasing pH increases soil corrosivity. The pH of most soils falls within the range of 3 to 10. Typically, a neutral soil pH range is considered to be 6.5 to 7.5. Above 7.5 is considered alkaline and below 6.5 is considered acidic.

Soil pH is often considered to be one of the controlling factors in underground corrosion. Soil pH is a measure of the environment's hydrogen-ion activity. In low pH environments (acidic), the protective corrosion films on steel are de-stabilized, resulting in localized or accelerated corrosion. In neutral pH environments, sulfate-reducing anaerobic bacteriological corrosion may occur. In high pH environments (alkaline), steel develops protective passive films.

Soil pH's along the route are likely to vary significantly (approximately 3-8). The varying pH may present localized corrosion conditions that will need to be addressed.

Chloride ions are generally harmful, as they participate directly in anodic dissolution reactions of metals and their presence tends to decrease the soil resistivity. They may be found naturally in soils as a result of brackish groundwater, historical geological sea beds or from external sources such as de-icing salts applied to roadways. The chloride ion concentration in the corrosive aqueous soil electrolyte will vary, as soil conditions alternate between wet and dry.

Chloride measurements are typically in units of ppm or mg/Kg. Chlorides in the range of 0-200 ppm are considered low and are typically not a significant corrosion control concern. Chlorides between 200-500 ppm are considered minimal and may present a corrosion mechanism that should be considered. Chloride concentrations greater than 500 ppm may present a significant corrosion control concern and should be addressed accordingly.

Soil chloride concentrations along the route are likely to vary significantly (approximately 0-500+). The varying chloride concentrations may also present localized corrosion conditions that will need to be addressed.

The presence of sulfates in soils can pose a significant risk to underground metallic structures because sulfates can be converted to highly corrosive sulfides by anaerobic sulfate reducing bacteria (SRB). Microbiologically influenced corrosion (MIC) is one of the most serious forms of corrosion attack because it causes accelerated localized pitting. MIC may be a significant corrosion concern in soils with high sulfate concentrations and an anaerobic and neutral pH environment.

Sulfate measurements are typically in units of ppm or mg/Kg. Sulfates in the range of 0-50 ppm are considered low and are typically not a significant corrosion control concern. Sulfates between 50-150 ppm are considered minimal and may present a corrosion mechanism that should be considered. Sulfates concentrations greater than 150 ppm may present a significant corrosion control concern and should be addressed accordingly.

Corrosion research has indicated that MIC is often associated with disbonded coatings and pipe surfaces blocked from adequate cathodic protection current densities. Tightly bonded coatings and adequate levels of cathodic protection should be used where MIC may occur.

Soil sulfate concentrations along the route are likely to vary significantly as well (approximately 0-150+). The varying concentrations may also present localized corrosion conditions that will need to be addressed.

The transfer of electrons between chemical substances determines the redox potential of a soil. The term redox comes from oxidation/reduction potential and is typically measured in units of Millivolts. Oxidation occurs when a substance loses an electron and reduction occurs when a substance gains an electron.

The redox potential of a soil is important, because the most common sulfate-reducing bacteria can only live in anaerobic conditions. A redox potential greater than +100 mV demonstrates that the soil is sufficiently aerated, preventing sulfate reducers from forming. Potentials of 0 to + 100mV may or may not indicate anaerobic conditions. A negative redox potential indicates the anaerobic conditions in which sulfate-reducing bacteria may exist. Typically, heavy clays and organic soils can be anaerobic.

Once again, Redox levels along the route are likely to vary significantly (approximately -100 to +100). The varying levels may also present localized corrosion conditions that will need to be addressed.

Another concern is the impact that seasonal freeze/thaw cycles will have on the ability of the CP system to protect the pipeline. As the ground freezes, the resistivity increases dramatically and the electrochemical corrosion process is slowed to an imperceptible level. However, the higher soil resistivities may also change the current distribution of the CP system, thus creating a potential barrier to CP current flow. Areas with large masses of water and free flowing water such as peat bogs and river crossings may not freeze for months or at all during the winter. These areas will remain corrosive and will need adequate levels of cathodic protection when the system may be least capable of delivering it.

Backfill specifications are also extremely important to the longevity of the pipeline and performance of the CP system. Sand and small rounded pea gravels provide the best bedding from a corrosion control perspective because they minimize coating damage and are conducive to CP current flow. CP current requirements are linear to the amount of coating damage on a pipeline, all other factors being equal. Each coating defect then becomes a potential source of external corrosion, which if not adequately protected could cause premature failure. A lesson learned from the TAPS pipeline replacement at the Atigun River was that sharp angular backfill easily cut through heavy polyethylene tape and the underlying fusion bonded epoxy coating. This resulted in water contacting the pipeline and the ultimate replacement of approximately 8.5 miles of buried line under the main river channel.

Floatation & Soil Stress:

The line will be in shallow burial, seasonally wet and frozen areas, discontinuous soils, and in permafrost areas. Being a gas pipeline, the line will tend to be naturally buoyant. The fuel gas line serving TAPS Pump Stations 2 through 4 is also an ambient gas line with some pre-cooling. It has floated to the surface in several locations and had to be reburied.

Buoyancy can place significant soil stresses on a coating. The more a line is prone to movement, the more soil stresses are placed on it. These stresses cause the backfill to rub against the pipe promoting the development of coating defects. If the line rises, it may pass through the covering layer of protective fill and encounter larger rocks, stones or sharp gravels that were used to fill the trench.

In areas where seasonal water tables may rise to a point near the surface, weight coating or anchor blocks may need to be considered. Weight coatings need to pass CP current and any metallic reinforcing used to support the coating must be electrically isolated from the pipe. If anchor blocks are used, they need to be padded so as not to damage the pipe or coating. Continuous weight coated pipe is preferred over anchor blocks from a corrosion control perspective.

Additional concerns about soil stress and subsequent damage to coatings are likely to be encountered on steep slopes and shot rock ditches where skin friction and cement anchors are used to restrain the pipeline. In these high abrasion areas, the coating system should be supplemented with a proven rock shield protective covering that is compatible with cathodic protection.

Current Distribution:

The high degree of variability in soil types, water content and freeze/thaw activity make the modeling of current distribution difficult. Computer models used for this type of analysis are only as good as the data fed into them and only work on a macro scale. Most pipeline companies install their CP equipment based on best estimates and historical performance data and then conduct detailed CP surveys over the first several years to adjust the system and correct any deficiencies noted during the surveys. It should be anticipated that the CP systems for the spur line will follow this trend and system adjustments and modifications will likely be required for several years.

Telluric Currents:

The earth's surface and crust is a combination of water, mineral formations and organic matter. From an electrical perspective, it can be viewed as a semiconductor. The earth's magnetic field is variable from place to place and can change significantly in extreme northern and southern latitudes due to impingement of the solar wind on the magnetosphere and the impact of charged particles from this wind interacting with the ionosphere. Within the ionosphere there are streams of charged particles which form what is called an electrojet. An analogous phenomena is the jet stream which consists of high altitude winds which undulate and flow in a generally west to east direction in the northern latitudes. As it circles around the poles, the electrojet discharges a large electromagnetic field. This field is coupled to the earth's surface and can cause local or regional variations in the earth's magnetic field depending on the size of the impact from geomagnetic storms. Geomagnetic storms are caused by surges or changes in intensity of the solar radiation from the sun. Changes are often the result of solar flares, sunspots or the orbits of planetary bodies like the moon. Research has shown a direct correlation between solar sunspot cycles and telluric current activity. The solar cycle lasts between 10 and 12 years and will reach a low in late 2006 or early 2007. The next peak should occur from late 2010 to spring of 2012. Visual indications of upper atmospheric disturbances can be seen in the northern lights as they dance across the night sky. The frequency of northern light activity also coincides with the solar cycle. The changes in the earth's magnetic field can cause local or regional variations in the electrical potential (voltage) of the earth's crust. These potentials rise and fall as magnetic storms pass and the earth's crust rebalances itself by exchanging current between high a low potential regions. These earth currents are known as "telluric" currents. While these trends in the frequency of telluric events are predictable, the magnitude and intensity of specific telluric current events are not. The largest events tend to occur during peaks in the solar sun spot cycle, but large single events can occur at almost any time in the cycle.

The concern over telluric currents is that they can not be controlled. Where they come into contact with pipelines, they can collect and discharge using the line as a low resistance path between regions of high and low potential. Where current collects on a line, the CP levels are increased. Where it discharges, the CP levels decrease. When CP levels get too high they can cause coatings to fail and in worst case conditions can actually damage the pipe by making it susceptible to cracking. Where CP is insufficient, corrosion is accelerated. Where the current leaves the pipeline in concentrated locations, severe pitting can occur that is proportional to the amount of current discharged from the site. Iron corrodes at a rate of 15 to 20 pounds per amp-yr of current flow. Given this information, it is critical to address the safe collection and discharge of telluric currents on any well coated pipeline.

To address this issue on TAPS the original designers used zinc ribbon anodes installed near the bottom quadrant on each side of the pipe within the thaw bulb. Others have used what are referred to as "dump anodes" which are usually clusters of magnesium anodes connected to the pipeline at 2 to 3 mile intervals for the purpose of discharging or "dumping" unwanted telluric current. For both spur line route options, telluric currents will be an issue. Using an impressed current system means the use of dump anodes is a likely consideration.

Another issue is that telluric currents can influence as little as a few miles of pipeline or as much as several hundred miles of pipeline. TAPS has documented evidence that significant telluric events can generate currents in excess of 2,000 amps DC on its pipeline. Pipe to soil voltage differentials in excess of 20 volts DC have also noted. Events like this can simply overwhelm most CP systems; however, these events are usually short lived, lasting from a few minutes to several days. They also tend to be oscillatory in nature which means they can both help and hinder the CP system.

Telluric current effects should be accounted for by installing resistive bonds and galvanic anodes (current discharge capabilities) as determined by the final design. Removing the IR drop influences, due to telluric currents, from CP testing and monitoring is covered later of this report.

*HAARP (**H**igh Frequency **A**ctive **A**uroral **R**esearch **P**rogram):*

The HAARP project could have an impact on the performance and operation of the spur gas line from Delta Junction to Palmer. The HAARP construction project was substantially completed in 1994 near Gakona, Alaska. It was built by the US Department of Defense to study the ionosphere phenomena. Modifications to the site continue in support of ongoing research. A cursory review of published information on the HAARP project indicates the system is capable transmitting sufficient energy to modify the behavior of the electrojet in the upper atmosphere. This same electrojet is influenced by the solar winds discussed in the telluric current section above. This influence could manifest itself as telluric current interference in the vicinity of the HAARP site. No such studies or third party validation of such a phenomena have been published. A representative from TAPS sits on the HAARP oversight committee and to date has not published any adverse findings due to HAARP operations. It currently appears that the HAARP system, in its current low power mode of operation, does not pose a significant threat to the corrosion control system on the proposed Delta junction option for a spur gas line. More detailed information on the HAARP project can be found at the following web site: HAARP Home Page

High Voltage Power Lines:

The spur line option from Fairbanks to Big Lake runs next to and in some cases appears to cross the right-of-way of a high voltage electrical power transmission lines. This can be a potentially dangerous situation if the line is not properly grounded and AC interference mitigation measures are not properly implemented at the time of construction.

It is recommended that a complete fault current coupling analysis be completed before construction activities in these areas begin. Reach and touch potentials need to be maintained at safe levels for workers and those who have incidental contact with the pipeline or its electrically connected components such as CP test stations. Fault currents can damage the line where AC current collects and discharges from the line. The use of solid state isolation devices that pass fault currents back to the electrical system while not passing CP current can be very effective at mitigating potential damage from ground fault events without compromising the effectiveness of the CP system.

Stress Corrosion Cracking (SCC):

SCC is known to occur under a narrow range of conditions in which cyclical stresses and environmental conditions in the soil combine to cause a form of cracking in the steel known as stress corrosion cracking. This most frequently occurs within a short distance of the compressor stations, where pressure in the pipeline is less constant, the line is still warm from the hot gases exiting the compressors and the CP system is nearby and is operating at high levels.

SCC can occur in both alkaline and neutral pH soils. If basic salts such as sodium or calcium hydroxide are present in the soil, high pH environments can occur at the pipe's surface. This warm caustic environment can increase the susceptibility of the pipe to SCC.

SCC in neutral pH environments is less clear cut and more variables need to be considered. In order to have SCC, the line needs to experience three simultaneous events. The line must see tensile stresses that are in the range to initiate SCC, the line must be made of a pipe material susceptible to SCC and an environment that supports the development of SCC must exist.

Lower line pressures, changing pipeline materials or thickness, or modifying the environment around the pipe (such as lowering the temperature of the gas line) can all be used to mitigate the risk of an SCC failure. Once a line is installed, the best ways to detect SCC are through the use of crack detecting smart pigs and direct assessment of the pipeline using NDT methods such as magnetic particle tests.

Electrical Isolation:

It is common practice to electrically isolate the line piping between compressor stations from the compressor station piping. The primary reason is that facility piping, power conduits, reinforcing steel, tank bottoms and a host of other buried metallic structures are commonly bonded together for grounding purposes, lightning protection, and convenience. This huge increase in exposed bare metal can substantially increase the demands on the CP system and detract from the systems ability to protect the pipeline. Due this situation compressor stations often employ a local dedicated CP system consisting of distributed anodes in close proximity to the buried gas lines within the compressor station perimeter.

Installing isolation devices can create problems when in proximity to high voltage power lines and in areas where telluric currents are present. Careful design analysis is needed to develop strategies that will effectively and reliably reduce AC reach and touch potentials as well as bleed off or shunt telluric currents to a safe discharge point.

Fittings should be used to electrically isolate the compressor station piping from the transmission line piping and the various buildings; however resistive bond stations should be installed to allow controlled amounts of protective current to be distributed between the station piping and the transmission line.

Road Crossings:

Whenever possible, cased road crossings should be <u>avoided</u>. It is far better to install the pipeline deeper and provide more cover to protect the line from traffic damage than it is to install a cased crossing. Cased crossings have a long history of failure, create zones of unprotected (CP) piping, can damage the line when internal support systems fail, can increase stress on the line if settlement occurs and create an ongoing testing, monitoring and repair problem.

Atmospheric Corrosion:

The fusion bonded epoxy coating currently being proposed for this line is not intended for atmospheric exposure and will likely break down over time when exposed to the suns UV rays. It is recommended that exposed piping be coated with an epoxy primer and a suitable urethane top coat to protect the underlying steel pipe.

Buried Field Joints:

Coating of field joints is often problematic and requires specific attention during the design and construction phases of this project. If field coatings are not applied properly, premature coating failure will likely occur. This could result in a significant load increase to the CP system or possible pipeline failure if insufficient levels of cathodic protection current are not available to the area. Additionally, corrosion under disbonded coatings may also occur, which could lead to premature failures.

Testing & Monitoring

Regulations:

The primary governing criteria for the construction and operation of natural gas transmission lines of the type proposed is Title 49 CFR Part 192. The US Department of Transportation (DOT) regulations Title 49 CFR Section 192.465 states:

(a) Each pipeline that is under cathodic protection must be tested at least once each calendar year, but with intervals not exceeding 15 months, to determine whether the cathodic protection meets the requirements of §192.463. However, if tests at those intervals are impractical for separately protected short sections of mains or transmission lines, not in excess of 100 feet (30 meters), or separately protected service lines, these pipelines may be surveyed on a sampling basis. At least 10 percent of these protected structures, distributed over the entire system must be surveyed each calendar year, with a different 10 percent checked each subsequent year, so that the entire system is tested in each 10–year period.

(b) Each cathodic protection rectifier or other impressed current power source must be inspected six times each calendar year, but with intervals not exceeding 2 1/2 months, to insure that it is operating.

(c) Each reverse current switch, each diode, and each interference bond whose failure would jeopardize structure protection must be electrically checked for proper performance six times each calendar year, but with intervals not exceeding 2 1/2 months. Each other interference bond must be checked at least once each calendar year, but with intervals not exceeding 15 months.

(d) Each operator shall take prompt remedial action to correct any deficiencies indicated by the monitoring.

Industry Standards:

NACE International Standard RPO169 lists the criteria and other considerations for determining the adequacy of a cathodic protection system. Three criteria are suggested for demonstrating that adequate cathodic protection has been achieved:

1. Section 6.2.2.1.1 states, ‘A negative (cathodic) potential of at least 850 mV with the CP applied. This potential is measured with respect to a saturated copper/copper sulfate reference electrode (CSE) contacting the electrolyte. Voltage drops other than those across the structure to electrolyte boundary must be considered for valid interpretation of this voltage measurement.’
2. Section 6.2.2.1.2 states, ‘A negative polarized potential of at least 850 mV relative to a saturated copper/copper sulfate reference electrode.’
3. Section 6.2.2.1.3 states, ‘A minimum of 100 mV of cathodic polarization between the structure surface and a stable reference electrode contacting the electrolyte. The formation or decay of polarization can be measured to satisfy this criterion.’ The most common method to measure a polarized potential, without effects of IR-drop, is to interrupt all sources of current. The measurement of polarization decay or formation also requires the ability to interrupt all current sources.

Section 6.3.2 of RPO169 states, ‘When it is impractical or considered unnecessary to disconnect all current sources to correct for voltage drop(s) in the pipe-electrolyte potential measurements, sound engineering practices should be used to ensure that adequate cathodic protection has been achieved.’ In accordance with this section, it is recommended to install CP coupon test stations along the entire length of the spur pipeline to assess the adequacy of the cathodic protection system and to correct for voltage drops including those associated with telluric currents (See Appendix C for an example drawing of a CP coupon installation).

CP testing is required to be conducted annually and may consist of test station and close interval pipe to soil voltage measurements using a $Cu/CuSO_4$ reference electrode. Other measurement types such as DCVG and side drain surveys may also be conducted to isolate problems.

CP coupons represent best available technology for monitoring CP effectiveness in this environment. Coupons should have a baseline set of potential readings taken after they are installed and then again after CP has been applied to the pipeline. A two coupon system is recommended so that native or free corroding potentials can be determined without waiting long periods for polarization decay. This will speed summer surveys and improve survey crew efficiency.

Test Station Spacing and Monitoring:

It is recommended to install one CP coupon test station with dual coupons (CP and free corroding coupons) approximately every mile, in high consequence areas, and where there are significant terrain changes. Coupon size should be optimized for 20-inch diameter line.

Although cathodic protection coupon technology is not new, it must be applied with an understanding of the underlying principles behind its use. Cathodic protection coupon technology may be theorized in two ways:

1. The coupon adds an additional “load” to the cathodic protection system. When electrically connected to the pipe, the coupon becomes a part of the cathodic protection circuit and requires current to protect the surface area of the coupon. If adequate current is available to protect a coupon sized to represent a large pipe coating defect (coupon increases the “load’ of the system), a sufficient amount of current is available, at the coupon location, to protect the pipe.
2. The coupon has a similar potential as that of a pipeline “holiday” or coating defect. Coupons are typically sized to represent a large coating defect. If the coupon potential indicates an adequate level of cathodic protection, pipeline coating defects, of similar size, have similar potentials, and therefore the pipeline has an adequate level of cathodic protection. This theory assumes that a large pipeline coating defect represents a conservative potential (more positive) as compared to smaller defects.

Coupons assess the adequacy of a cathodic protection system and may be used to determine compliance with criteria outlined by Federal regulations and industry standards. A minimum of -850 mV (CSE) polarized potential and/or 100 mV polarization are the criteria used to indicate whether adequate cathodic protection has been achieved.

It should be noted that a measurement error can occur when reading the corrosion coupon potential, while the CP coupon is connected to the pipe and the cathodic protection system is “on”. This type of error may occur when the reference electrode is placed down the dip tube or is placed on the ground surface. The error is attributed to the potential gradient that exists around the CP coupon when connected to the pipe and cathodic protection system. Elimination of this interference is achieved by disconnecting the CP coupon lead wire from the pipeline lead wire and interrupting the circuit.

The impact of meter input impedance has been investigated for several years to determine the effects on potential measurements. Field data indicates that negative potential shifts, in excess of 100 mV, may occur when the input impedance is increased from 10 M-ohm to 1 G-ohm (depending on soil resistivities and contact resistances). Standard voltmeters are equipped with an input impedance of 10 M-ohm. To overcome high contact resistances, high impedance buffers may be needed in series with the monitoring instrumentation.

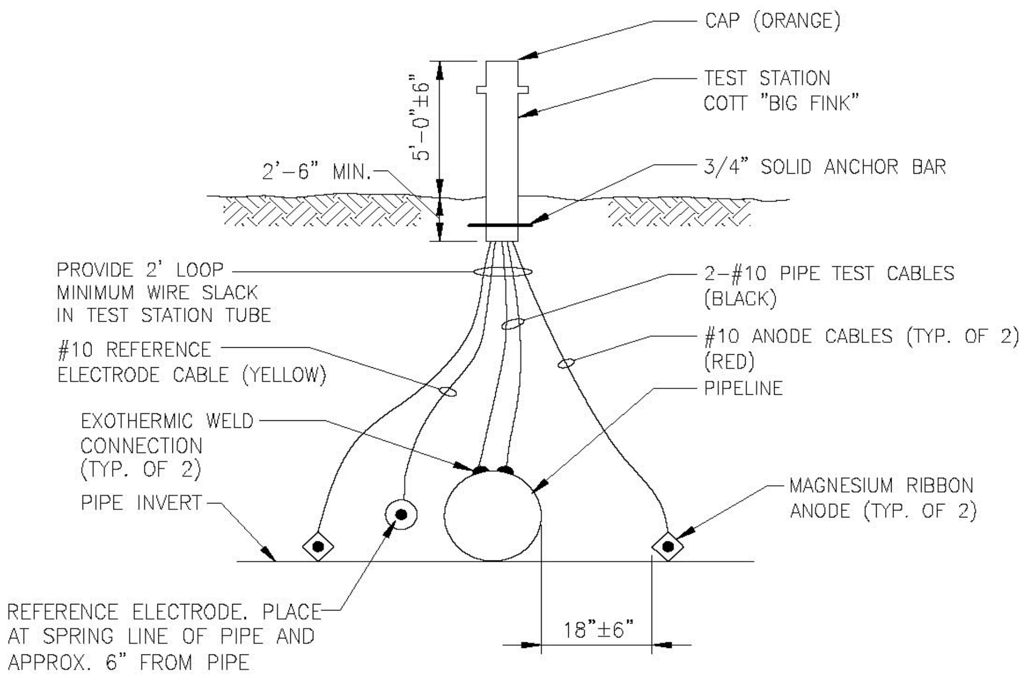
Smart Pigs:

An effective pipeline corrosion control plan should include the implementation of a Pipeline Integrity Management Plan (PIMP). Such a plan is called for 49 CFR Part 192, Sections 901 to 951. While the requirements don't specifically call for the ability to pig a line, it is highly recommend to configure the spur line to accept instrumented smart pigs as well as cleaning pigs.

Smart pigs can be used to test for ovality, settlement, corrosion (internal and external) as well as cracking. These tools are often essential to a highly effective PIMP. They can provide validation of the effectiveness of the CP system, as well as detect other potential problems in advance of an incident or failure.

~End of Report~

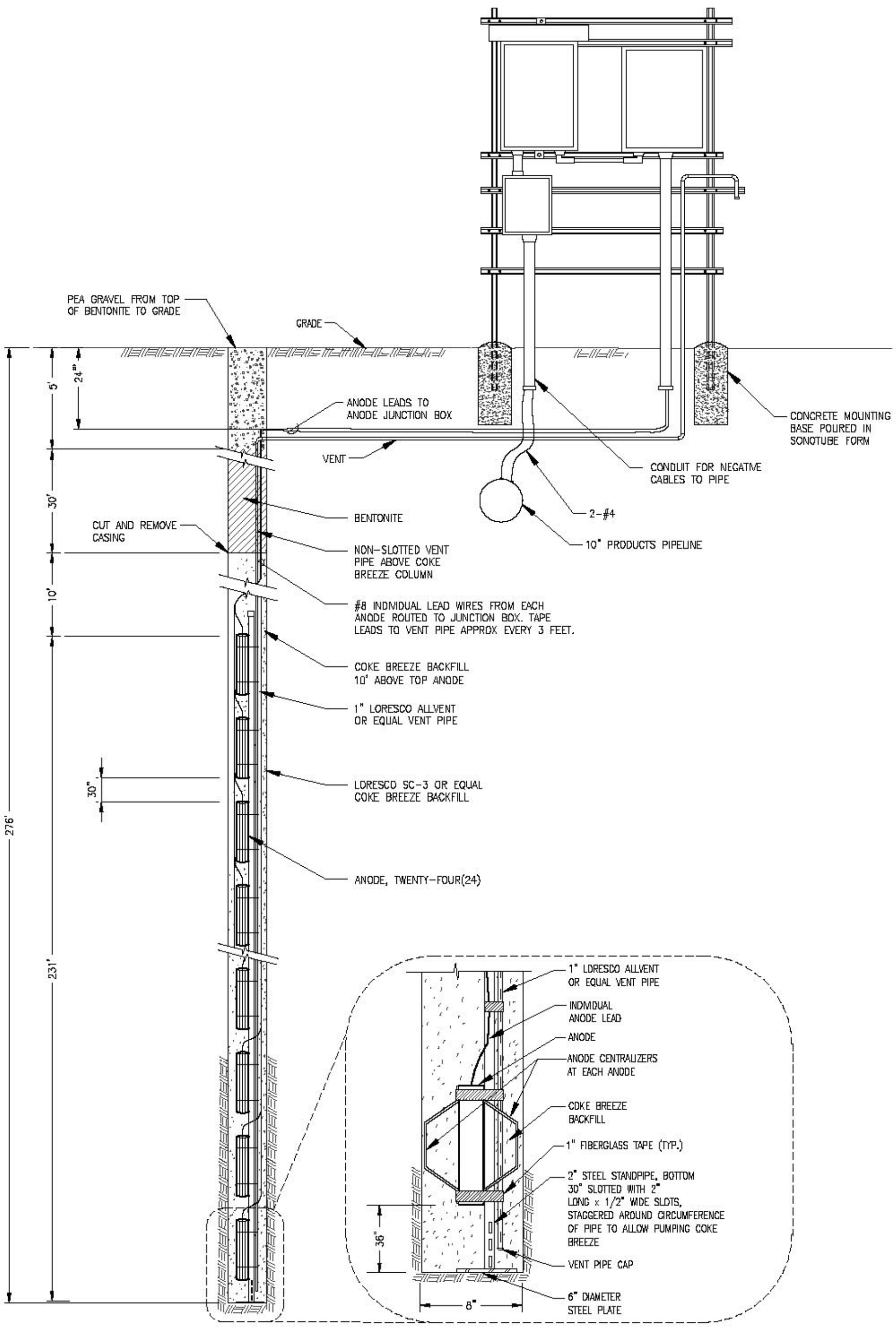
Appendix A –Typical Anode Ribbon Installation - Sacrificial Anode CP System



TEST STATION AND MAGNESIUM RIBBON ANODE INSTALLATION

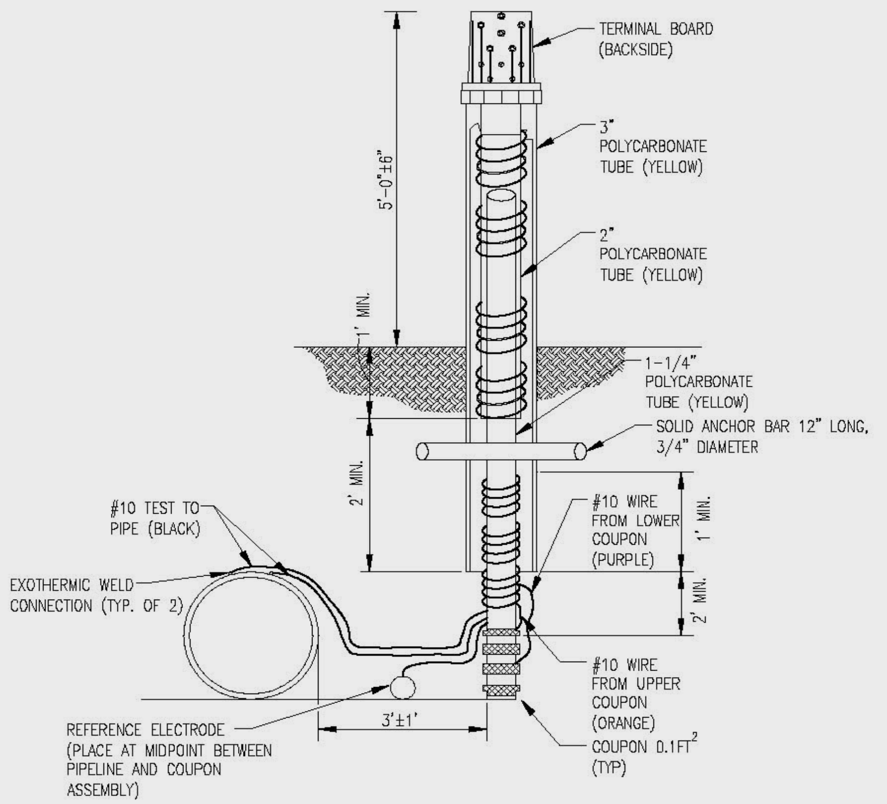
1 CP1 NTS

Appendix B –Typical Deep Anode Groundbed - Impressed Current CP System



1 DEEP ANODE GROUNDBED DETAIL
CP1 NTS

Appendix C –Typical CP Test Station With Coupons



NOTES:

1. TEST STATION SHALL BE FINKPROBE, AS MANUFACTURED BY COTT INDUSTRIES. ALL TUBES TO BE MADE OF SINVET R-204 POLYCARBONATE. TERMINAL BOARD MATERIAL IS MAKROLON T-7855 POLYCARBONATE.
2. TEST STATION CAP – DARK BLUE
3. UNDERGROUND CABLES UTILIZED FOR THE CATHODIC PROTECTION CIRCUIT SHALL BE #10 AWG, STRANDED COPPER CONDUCTOR WITH HMWPE OR RHH-RHW INSULATION RATED FOR 600 VOLTS AND BELOW GRADE USE. CABLE SPLICES SHALL NOT BE PERMITTED UNLESS OTHERWISE SPECIFIED OR SHOWN. CABLES SHALL BE COLOR CODED AS SHOWN. COLOR SHALL BE IMPREGNATED IN THE INSULATION MATERIAL. ALL CABLES SHALL BE LABELED WITH THE FOLLOWING IDENTIFIERS:
   - CONDUCTOR SIZE
   - TYPE OF INSULATION
4. SOIL TO BE IN FULL CONTACT WITH THE COUPONS. SOIL IN CONTACT WITH THE COUPONS SHALL BE THE SAME AS THAT IN CONTACT WITH THE PIPELINE.
5. REMOVE PACKAGING TAPE FROM FROM COUPONS PRIOR TO INSTALLATION.
6. PLACE ONE HALF OF A TEST STATION CAP FULL OF SCREENED NATIVE SOIL DOWN THE 1" TUBE.
7. LEAVE THE SHORTING BAR DISCONNECTED FROM THE TERMINAL BLOCK FOR A MINIMUM OF 4 WEEKS AFTER COUPON TEST STATION INSTALLATION.

1 CP1 **CP COUPON TEST STATION**

NOT TO SCALE